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February 1, 2019

VIA: ELECTRONIC FILING

Mr. Adam J. Teitzman
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor; FPSC Docket No. 20190001-EI

Dear Mr. Teitzman:

Attached for filing in the above docket is Tampa Electric Company's Responses to Staff's First Data Request (Nos. 1-19) dated January 25, 2019.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment

cc: Suzanne Brownless

For the purpose of these questions, please refer to either the Company's Mid-Course Correction Petition (Mid-Course Petition), or to the Company's 2019 Projection filing, dated August 24, 2018, and specific page references identified below.

1. Refer to Page 3, Paragraph 9, where the Mid-Course Petition states the total fuel and purchased power under-recovery for 2019 is estimated to be $122,731,324.

a. What portion of this amount is based on actual, final amounts from 2018?

b. Is the remaining portion based on estimated amounts for January through December 2019? Briefly explain your response.

A. a. An under-recovery of $43,986,397 is the final 2018 true-up amount.

b. Yes. In December 2018, based on the magnitude of the company's November 2018 under-recovery and higher NYMEX natural gas futures prices at that time than when the original projection was prepared, the company began work on a re-projection of 2019 fuel costs. Tampa Electric identified a need for a mid-course adjustment to the fuel and capacity factors and filed the mid-course petition and supporting schedules on January 15, 2019.

2. What values (numerator and the denominator amounts) did the Company use to support the 24.9 percent figure shown on Page 3, Paragraph 9 of the Mid-Course Petition?

A. $122,731,324 / $493,445,362 = 24.9%

3. What values (numerator and the denominator amounts) did the Company use to support the 16 percent figure shown on Page 3, Paragraph 9?

A. $78,744,927 / $493,445,362 = 16.0%

4. Refer to Page 3, Paragraph 10, and Schedule H1 from the Mid-Course Petition to the answer the following:

a. Identify what the primary and secondary drivers were that caused the "increase in the projected cost of natural gas" for the 2018 period.

b. Identify what the primary and secondary drivers are (or were) that caused the "increase in the projected cost of natural gas" for the projected 2019 period.

c. Schedule H1 includes a column labeled as showing Actual / Estimated data for 2018. For the data presented in this column, please identify the last month whereby "actual" data from 2018 was incorporated in what is reflected in this column.

d. Schedule H1, Line 44, under the column labeled as Estimated 2019, reflects that the projected fuel cost per MMBTU for natural gas will be $4.20. Does this value represent a forecast of the commodity price only, or the commodity price plus delivery?

e. Although the Mid-Course Petition does not reference coal, has the Company's projected costs for coal changed for 2019 since the Company prepared its projection filings? Please explain your response.

A. a. Actual natural gas prices were greater than Tampa Electric projected for the latter six months of 2018 in its 2018 actual/estimated filing. The rise in natural gas prices was driven primarily by working gas storage levels across the nation being well below the historic five-year average. These lower storage levels, coupled with early season cold weather in the northeast, caused market prices to increase from a fear of insufficient gas in storage for the winter of 2018/2019.

b. NYMEX natural gas futures contract prices for the projected 2019 period were lower when the original projection was prepared. In addition to the storage level concern in 2018, 2019 prices also increased due to expectations that refilling storage would create incremental demand for natural gas and that gas supply may decline due to lower associated natural gas production as a result of lower oil production due to the drop in crude oil prices.

c. June 2018. This information ties to the company's 2018 actual/estimated filing, submitted as Exhibit No. PAR-2, Document No. 1, page 5 of 30, in Docket No. 20180001-EI.

d. It represents the commodity price plus delivery.

e. No, the company's projected cost of coal has not changed. Current expectations are for coal prices to remain relatively stable compared to projected prices at the time the original projection was prepared.

5. Refer to Page 3, Paragraph 10. Please provide more detailed information about the revisions to "planned power purchases," and the projected impact that these revisions will have on fuel and capacity revenues.

A. At the time the original projection was prepared, Tampa Electric expected to purchase economic power with an associated capacity payment and included estimated costs to reflect it. This expectation was based on the availability of such products in recent years. However, when the company went to the market, that type of power purchase was no longer available at the expected price, and an energy-only purchase was the most cost-effective solution to provide customers with economic power. Therefore, Tampa Electric executed the purchase with an associated energy charge and no capacity charge, resulting in a cost variance to expected revenues for the company's fuel and capacity factors.

Capacity revenues are reduced by the proposed mid-course adjustment as all costs are removed from the clause. The collection of the first three months' revenues at the current approved rate, the credit of projected capacity revenues for wholesale power sales, and the collection of the final 2018 under-recovery amount are offsetting factors that result in a capacity clause credit to customer bills over the April 2019 through December 2019 period, if the mid-course petition is approved.

Fuel revenues are increased by the proposed mid-course adjustment since the power purchase selected is recovered solely through the fuel clause and was not included in the original projection.

6. Refer to Page 3, Paragraph 11 of the Mid-Course Petition. Other than the instant matter, please identify any pending rate adjustment matters that may trigger a billing change for TECO customers for the period April through December 2019.

A. Tampa Electric is not aware of any pending rate adjustment matters that may trigger a billing change for its customers during the period April through December 2019.

7. Refer to Page 3, Paragraph 11 of the Mid-Course Petition. Please provide more detailed information about the Company's request to not include the 2018 Final True-up balance in its request for a mid-course adjustment.

A. Tampa Electric did not include the 2018 fuel final under-recovery amount in its request for mid-course adjustment primarily due to two factors. First, the impact of recovering the entire $122 million under-recovery would have a significant impact on customer rates, and would be even greater given the recovery period is a partial year instead of the full year over which costs are usually distributed. Second, the normal schedule for recovery of this amount suggests a final true-up filing in March 2019 with recovery in 2020; given this schedule, even if Tampa Electric's natural gas projections are lower than projected for the mid-course adjustment, the final 2018 true-up under-recovery will offset such a potential over-recovery for 2019.

8. Refer to Page 4, Paragraph 13 of the Mid-Course Petition. Is it correct that the "E-Schedules" in Exhibit B do not reflect the total fuel and purchased power under-recovery for 2019, which is estimated to be $122,731,324? If so, please submit a complete set of "E-Schedules" to reflect this amount.

A. The E Schedules provided in Exhibit B do not reflect the total fuel and purchased power under-recovery for 2019.

See the attached E Schedules that reflect the total fuel under-recovery of $122,731,324. Only Schedules E1, E1-C, E1-D, E1-E, E2, and E10 differ from the schedules in Exhibit B when the total fuel under-recovery of $122,731,324 is reflected.

TAMPA ELECTRIC COMPANY **SCHEDULE E1**
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	574,179,130	19,485,150	2.94675
2.	Nuclear Fuel Disposal Cost	0	0	0.00000
3.	Coal Car Investment	0	0	0.00000
4a.	Big Bend Units 1-4 Igniters Conversion Project	4,462,045	19,485,150 (1)	0.02290
4b.	Adjustment	0	0	0.00000
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4b)**	**578,641,175**	**19,485,150**	**2.96965**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	0	0	0.00000
7.	Energy Cost of Economy Purchases (E9)	32,887,040	894,370	3.67712
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	2,641,870	90,120	2.93150
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**35,528,910**	**984,490**	**3.60886**
11.	**TOTAL AVAILABLE KWH (LINE 5 + LINE 10)**		20,469,640	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	271,470	10,330	2.62798
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	453,055	11,990	3.77860
14.	Gains on Sales	58,965	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**783,490**	**22,320**	**3.51026**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		524	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**613,386,595**	**20,446,796**	**2.99992**
20.	Net Unbilled	NA (1)(a)	NA (a)	NA
21.	Company Use	1,115,970 (1)	37,200	0.00573
22.	T & D Losses	27,814,174 (1)	927,164	0.14277
23.	System MWH Sales	613,386,595	19,482,432	3.14841
24.	Wholesale MWH Sales	0	0	0.00000
25.	Jurisdictional MWH Sales	613,386,595	19,482,432	3.14841
26.	Jurisdictional Loss Multiplier			1.00000
27.	Jurisdictional MWH Sales Adjusted for Line Loss	613,386,595	19,482,432	3.14841
28.	True-up (2)	79,734,429	15,300,631	0.52112
29.	Total Jurisdictional Fuel Cost (Excl. GPIF)	693,121,024	19,482,432	3.66953
30.	Revenue Tax Factor			1.00072
31.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	693,620,071	19,482,432	3.67217
32.	GPIF Adjusted for Taxes (2)	(2,261,019)	19,482,432	(0.01161)
33.	**Fuel Factor Adjusted for Taxes Including GPIF**	691,359,052	19,482,432	3.66056
34.	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**3.661**

(a) Data not available at this time.
(1) Included For Informational Purposes Only
(2) Calculation Based on Jurisdictional MWH Sales

TAMPA ELECTRIC COMPANY **SCHEDULE E1-C**
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: APRIL 2019 THROUGH DECEMBER 2019

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2019 through December 2019)	($2,261,019)	
	B. TRUE-UP OVER / (UNDER) RECOVERED (April 2019 through December 2019)	($79,734,429)	
2.	TOTAL SALES		
	(April 2019 through December 2019)	15,300,631	MWh
	(January 2019 through December 2019)	19,482,432	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR (January-December)	**(0.0116)**	Cents/kWh
	B. TRUE-UP FACTOR (April-December)	**0.5211**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: APRIL 2019 THROUGH DECEMBER 2019

SCHEDULE E1-D

					NET ENERGY FOR LOAD (%)	FUEL COST (%)
				ON PEAK	29.77	$23.94
				OFF PEAK	70.23	$22.10
					100.00	1.0833
			TOTAL		ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$458,831,946			
2	MWH Sales (Jurisd)	(Sch E1 line 25)	15,300,631			
2a	Effective MWH Sales (Jurisd)		15,279,017			
3	Cost Per KWH Sold	(line 1 / line 2)	2.9988			
4	Jurisdictional Loss Factor		1.00000			
5	Jurisdictional Fuel Factor		NA			
6	True-Up	(Sch E1 line 28)	$79,734,429			
7	TOTAL	(line 1 x line 4)+line 6	$538,566,375			
8	Revenue Tax Factor		1.00072			
9	Recovery Factor	(line 7 x line 8) / line 2a / 10	3.5274			
10	GPIF Factor	(Sch E1-C line 3a)	(0.0111)			
11	Recovery Factor Including GPIF	(line 9 + line 10)	3.5163		3.7170	3.4313
12	Recovery Factor Rounded to the Nearest .001 cents/KWH		3.516		3.717	3.431
13	Hours: ON PEAK			25.48%		
14	OFF PEAK			74.52%		
				100.00%		

Jurisdictional Sales (MWH)
April - December

Metering Voltage:	Meter	Secondary
Distribution Secondary	13,610,891	13,610,891
Distribution Primary	1,218,108	1,205,927
Transmission	471,632	462,199
Total	15,300,631	15,279,017

	Standard	On-Peak	Off-Peak
Distribution Secondary	3.516	3.717	3.431
Distribution Primary	3.481	3.680	3.397
Transmission	3.446	3.643	3.362
RS 1st Tier	3.202		
RS 2nd Tier	4.202		
Lighting	3.480		

SCHEDULE E1-E

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: APRIL 2019 THROUGH DECEMBER 2019

METERING VOLTAGE LEVEL	LEVELIZED FUEL RECOVERY FACTOR cents/kWh	FIRST TIER (Up to 1000 kWh) cents/kWh	SECOND TIER (OVER 1000 kWh) cents/kWh
STANDARD			
Distribution Secondary (RS only)		3.202	4.202
Distribution Secondary	3.516		
Distribution Primary	3.481		
Transmission	3.446		
Lighting Service (1)	3.480		
TIME-OF-USE			
Distribution Secondary - On-Peak	3.717		
Distribution Secondary - Off-Peak	3.431		
Distribution Primary - On-Peak	3.680		
Distribution Primary - Off-Peak	3.397		
Transmission - On-Peak	3.643		
Transmission - Off-Peak	3.362		

(1) Lighting service is based on distribution secondary, 17% on-peak and 83% off-peak

SCHEDULE E2

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
						ESTIMATED							TOTAL
	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	PERIOD
1. Fuel Cost of System Net Generation	55,450,306	46,332,675	49,739,014	44,924,422	48,860,560	48,145,031	52,050,700	52,186,875	48,288,859	43,274,434	40,603,623	44,322,631	574,179,130
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold [1]	81,474	65,692	73,540	68,936	66,229	70,352	57,555	67,392	55,072	69,754	43,415	64,079	783,490
4. Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
5. Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6. Payments to Qualifying Facilities	290,630	236,240	189,240	163,260	224,660	187,380	226,500	266,490	188,810	248,690	225,080	194,890	2,641,870
7. Energy Cost of Economy Purchases	102,520	492,910	796,830	593,710	575,020	5,716,820	5,713,760	5,516,000	5,572,520	5,974,220	823,900	1,008,830	32,887,040
8. Big Bend Units 1-4 Igniters Conversion Project	383,847	381,664	379,479	377,296	375,113	372,930	370,745	368,562	366,378	364,194	362,010	359,827	4,462,045
9. Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
10. TOTAL FUEL & NET POWER TRANSACTIONS	**56,145,829**	**47,377,797**	**51,031,023**	**45,989,752**	**49,969,124**	**54,351,809**	**58,304,150**	**58,270,535**	**54,361,495**	**49,791,784**	**41,971,198**	**45,822,099**	**613,386,595**
11. Jurisdictional MWH Sold	1,499,964	1,343,529	1,338,308	1,424,660	1,566,247	1,825,998	1,906,515	1,897,443	1,960,452	1,781,369	1,486,481	1,451,466	19,482,432
12. Jurisdictional % of Total Sales	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
13. Jurisdictional Total Fuel & Net Power Transactions (Line 10 * Line 12)	56,145,829	47,377,797	51,031,023	45,989,752	49,969,124	54,351,809	58,304,150	58,270,535	54,361,495	49,791,784	41,971,198	45,822,099	613,386,595
14. Jurisdictional Loss Multiplier	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	
15. JURISD. TOTAL FUEL & NET PWR. TRANS. Adjusted for Line Losses (Line 13 * Line 14)	**56,145,829**	**47,377,797**	**51,031,023**	**45,989,752**	**49,969,124**	**54,351,809**	**58,304,150**	**58,270,535**	**54,361,495**	**49,791,784**	**41,971,198**	**45,822,099**	**613,386,595**
16. Cost Per kWh Sold (Cents/kWh)	3.7431	3.5264	3.8131	3.2281	3.1904	2.9766	3.0582	3.0710	2.7729	2.7951	2.8235	3.1570	3.1484
17. True-up (Cents/kWh) [2]	(0.0360)	(0.0360)	(0.0360)	0.5211	0.5211	0.5211	0.5211	0.5211	0.5211	0.5211	0.5211	0.5211	0.5211
18. Total (Cents/kWh) (Line 16+17)	3.7071	3.4904	3.7771	3.7492	3.7115	3.4977	3.5793	3.5921	3.2940	3.3162	3.3446	3.6781	3.6695
19. Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
20. Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	3.7098	3.4929	3.7798	3.7519	3.7142	3.5002	3.5819	3.5947	3.2964	3.3186	3.3470	3.6807	3.6721
21. GPIF Adjusted for Taxes (Cents/kWh) [2]	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)	(0.0116)
22. TOTAL RECOVERY FACTOR (LINE 20+21)	**3.6982**	**3.4813**	**3.7682**	**3.7403**	**3.7026**	**3.4886**	**3.5703**	**3.5831**	**3.2848**	**3.3070**	**3.3354**	**3.6691**	**3.6605**
23. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	**3.698**	**3.481**	**3.768**	**3.740**	**3.703**	**3.489**	**3.570**	**3.583**	**3.285**	**3.307**	**3.335**	**3.669**	**3.661**

[1] Includes Gains
[2] Based on Jurisdictional Sales Only

SCHEDULE E10

TAMPA ELECTRIC COMPANY
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1,000 KWH

	Current Jan 19 - Mar 19	Projected Apr 19 - Dec 19	Difference $	Difference %
Base Rate Revenue	66.53	66.53	0.00	0.0%
Fuel Recovery Revenue	24.05	32.02	7.97	33.1%
Conservation Revenue	3.21	3.21	0.00	0.0%
Capacity Revenue	1.03	(0.10)	(1.13)	-109.7%
Environmental Revenue	2.22	2.22	0.00	0.0%
Florida Gross Receipts Tax Revenue	2.49	2.66	0.17	6.8%
TOTAL REVENUE	**$99.53**	**$106.54**	**$7.01**	**7.0%**

9. Please describe the Company's efforts in notifying its customers about the Mid-Course Petition. In your response, please state any website addresses or hyperlinks that customers can access for information about this matter.

A. The company issued a news release on January 15, 2019, which was also shared on social media, and it is available at the following web address:

https://www.tampaelectric.com/company/mediacenter/article/index.cfm?article=971

In addition, the company will provide a notice of proposed bill change with March 2019 customer bills. Paper bills will display a message describing the proposed rate changes. In their monthly new bill notification email, paperless customers will see a short explanation of the rate adjustment and a link to tampaelectric.com/rates where they can access the same information that is displayed on the printed bills.

After the Commission votes on this request, the company will issue another news release, which will also be available on the company website.

10. On what date does the April 2019 billing cycle begin?

A. April 2, 2019

Questions 11-16 pertain to the revised fuel forecast for 2019 that was prepared to support the Company's Mid-Course Petition.

11. Identify the date the revised fuel forecast for 2019 was prepared to support the Company's Mid-Course Petition.

A. The revised fuel forecast was prepared in mid-December based on a forward natural gas price forecast utilizing the NYMEX natural gas futures contract prices for the five-day period December 7, 2018 through December 13, 2019.

12. What was the average commodity price per MMBtu that was forecasted for natural gas, and how did it compare to the value projected in the older forecast?

A. The requested information is provided in the following table.

	Mid-course	**Projection**
Avg	3.230	2.789

13. What was the average delivered price per MMBtu that was forecasted for natural gas, and how did it compare to the value projected in the older forecast?

A. The 2019 original projection natural gas average delivered price per mmBtu is $3.82, and the mid-course petition price is $4.20 per mmBtu.

14. Were any new or different gas delivery arrangements incorporated into the revised fuel forecast than what were used when the projection forecast was prepared? If so, provide a detailed response.

A. No.

15. Please identify the forecasting sources that were used for preparing the Company's Mid-Course Petition for 2019. Include in your response whether any of these sources were new or different sources than what was used when the projection forecast was prepared.

A. Updated NYMEX natural gas futures contract prices were used for the 2019 natural gas forecast for Tampa Electric's mid-course petition. This is the same forecasting source and method as was used for the original petition. There were no new or different forecasting sources used compared to when the projection forecast was prepared.

16. Please identify the forecasting assumptions that were used for preparing the Company's Mid-Course Petition for 2019. Include in your response whether any of these forecasting assumptions were new or different than what was used when the projection forecast was prepared.

A. Other than updated natural gas prices, updates to expected purchased power prices and types for 2019, and known planned outage changes, there were no changes to the forecasting assumptions compared to when the projection forecast was prepared.

The changes in planned outages are summarized below.

Unit	Projection (Days)	Mid-Course (Days)	Delta (Days)
BB1	14	30	16
BB2	14	30	16
BB3	38	55	17
BB4	84	50	-34
BPS1	24	48	24
BPS2	24	24	0
PK1	30	41	11
PK2	10	19	9
	Total		27

For Questions 17-19, please refer to Page 16, Lines 23-24, of the Direct Testimony of J. Brent Caldwell, as filed in Docket No 20180001-EI on August 24, 2018.

17. Please explain the decision to use "five consecutive business days in April 2018" to develop the fuel price forecasts for 2019.

A. Tampa Electric uses the NYMEX natural gas futures contract prices averaged across five consecutive business days to smooth daily volatility in the NYMEX prices. Tampa Electric began preparation of its fuel price forecast for the fuel projection filing in April 2018 and used the NYMEX futures prices current when the forecast was produced.

18. Similar testimony from prior years indicates that TECO prepared its forward year fuel price forecasts for 2018 in May 2017, and the forward year fuel price forecasts for 2017 in June 2016. Please discuss generally the decision process involved in selecting the dates used to develop forward year fuel price forecasts.

A. The fuel price forecast process typically begins in May. Depending on other workload, the process may slip into June, which is considered undesirable as it greatly compresses the preparation and review time for the entire filing, or begin earlier than May, which is preferred.

19. Please identify any impediments to selecting a uniform time frame (e.g., the second week of June, or similar) for preparing forward year fuel price forecasts.

A. Preparation of the fuel price forecast must occur at the beginning of the process for preparing the fuel clause projection for filing, including the 6-month actual / 6-month estimated filing that is submitted in July. Using a specific, prescribed time period for the NYMEX futures forward contract prices would be possible; however, the following considerations would apply. First, the selected time period should not be later than May to allow sufficient time for preparation and review of the resulting projection filing. Second, the selection of the time period should allow the company the flexibility to account for market events that may cause anomalies in the forward price curve such as refinery outages, international crises, and extreme weather events.